CURRENT AND FUTURE ISSUES FACING HIGH-SULFUR MIDWESTERN COALS

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INTRODUCTION

Coal markets have been dramatically affected by the Clean Air Act (CAA) and its many amendments, and by price competition among fuels and between coals of different quality. Regulations regarding electricity generation, distribution and pricing now being eliminated. International concerns about global climate change will affect coal markets in the future. This paper presents an analysis of how these and other factors have affected high-sulfur coals in the past and how they will affect them in the future.

DEMAND-SIDE ISSUES

Coal demand in the U.S. increased from 523 million tons in 1970 to 1007 million tons in 1997. Electric utilities accounted for 61% of domestic total in 1970, and 90 % in 1997. Coal-fired power plants generated 46 % of the electricity for the utilities in 1970 and over 57 % in 1997 [1]. Nuclear electricity generation increased from 1.4 % of the total in 1970 to 22.5 % in 1995, but fell to 20.1% in 1997 due to plant safety and maintenance problems. The oil and natural gas price shocks in 1974 and 1979-81 resulted in significant fuel switching by electric utilities. By 1997, oil and natural gas-based electricity generation had fallen to 2.5% and 9.1% of the total respectively, well below their 1970 levels of 11% and 24%. Electricity generated by non-utility producers contributed an additional 3 to 12 percent to total electricity generated by utilities **(Figure 1)**. Available data indicate that natural gas is the preferred fuel of non-utility producers, thus increasing gas-based generation of electricity in 1997 to 14.5% of U.S. total. Growth in U.S. demand for electricity averaged about 4% per year in 1970, but declined to about 2% by 1997 **(Figure 2)**. However, increased post 1990 non-utility generation resulted in slowing down growth in utility generation to 1% in 1997 **(Figure 3).**

In 1991, the U.S. Department of Energy and four other institutions forecasted U.S. electricity demand to grow at 1.4 to 2.4% per year from 1990 through 2010 [2]. Subsequently published DOE Annual Energy Outlooks revised the forecast to 1.26% per year between 1995 and 2010 [3] [4], 1% per year for utilities and 3% for non-utility producers. These estimates indicate the continuation of the trends depicted in figures 2 and 3. Based on these forecasts, U.S. coal production in year 2010 is estimated to be about 1,225 million tons. Thermal conversion efficiency is a critical factor. A 1 percent increase in it can reduce coal demand by 2.5% or 30 million tons. Such a change is conceivable as less efficient, older plants are retired or their usage reduced.

REGULATORY ISSUES

Two sets of regulations affect coal markets: the Clean Air Act amendments (CAAA) of 1990 and the deregulation of the electricity generating industry. The potential for future regulation of "greenhouse gases" may already be affecting fuel choice decisions by utilities. The 1990 CAAA were the result of Congressional desire to create economic incentives and freer markets for pollution control. Accordingly, the mandatory 90% emission reduction was eliminated but a reduction in nation-wide SO_2 emissions of 5 million tons by January 1995 (Phase I) and another 5 million tons by January 2000 (Phase II) together with an overall cap on emissions at the year 2000 level were mandated. The mechanism to do this is the "pollution credit," which allows plants that reduce emissions below the legal limits to achieve a credit that they can sell to plants that are over the limit. Utilities in need of emission reduction can reduce emissions or purchase pollution credits in the market. The decision is to be made by individual companies on an economic basis. In the first phase of the 1990 CAAA that ended in 1995, a majority of plants opted for low-sulfur Wyoming coal or natural gas and created a large stock of pollution credits with few buyers. Consequently, the price of pollution credits fell from the originally predicted \$1,500 per unit (1 Unit = 1 ton of SO_2 per year) to \$65 to \$70 per unit [5] by March 1996. In October 1998, they were trading at \$160 to \$180 per unit [6].

To comply with the second phase of the 1990 CAAA, utilities have been switching to lower sulfur fuels for the past three years and an acceleration of the trend is likely in 1999. For example: Illinois Power, the largest consumer of high-sulfur coal in Illinois, has decided to switch to Wyoming coal in the next twelve months. Because the delivered prices of low- and high-sulfur coals are comparable in most states, demand for western coal is expected to rise through the year 2000 and possibly through 2010. After 2000, sulfur-free fuels such as natural gas will be preferred by users who must comply with the SO_2 emission "cap". Available technologies like Flue Gas Desulfurization (FGD) and Fluidized Bed Combustion (FBC), and emerging ones like Integrated Gasification Combined Cycle (IGCC) would permit coal-burning with little or no SO_2 emission. Decisions to use them, however, will depend on their total generating cost compared with the total cost of using sulfur-free fuels.

Emissions of nitrogen oxides (NO_x) are also regulated under the Clean Air Act. Some NO_x rules apply only to plants that are affected by CAA SO_2 regulations. Each affected unit must hold NO_x emissions below 0.45 or 0.5 lbs per million Btu, depending upon the boiler type. Stricter limits apply to ozone non-attainment areas. States must determine what approach is reasonable to achieve this goal.

The 1990 amendments also propose to control emissions of Hazardous Air Pollutants (HAPs). When regulations are established, they may affect coal use because up to 16 HAPs are known to be released by combustion. Of these, mercury is likely to be one of the first to be regulated. Resource Data International (RDI) recently estimated the cost of curbing mercury emissions to range between $0.5 billion and $7.8 billion annually and add up to 0.2 cents to the cost per kWh of electricity [7]. Mercury-free fuels would thus have an advantage over other fuels in the future.

Utilities have been "regulated monopolies." Customers within a utility's service area could only purchase electricity from that utility. A state commission determined the utility's rate of return on investment, and approved all expenses the company charged to consumers. Electric utilities are now being deregulated under the 1992 National Comprehensive Energy Policy Act. "Independent" unregulated power companies are now permitted. These independents are free to produce and sell electricity to anyone anywhere. Utilities are also now permitted to merge. Wholesalers who buy electricity for resale are free to purchase it anywhere, and utilities are required to provide transmission for a fair market charge. Retail customers, however, are still required to purchase electricity from the same utilities as before until state laws are amended.

Deregulation will likely intensify price competition among producers of electricity and force cost-cutting measures in the industry. Some of the consequences of the increased competition are as follows:
*Old low-efficiency and high-cost generating units will be retired earlier than planned.
*Lower-cost units will increase their capacity utilization (load factor).
*Independent producers will not have price or sales guarantees.
*Independent electricity distribution networks, including intra-city, may emerge.
*Gas-fired combined-cycle electricity generation may assume a greater role in production.
*Nuclear power plants may face economic hardships because of unrecovered investments, called the "stranded costs".
*Rural electric power supply companies facing loan servicing problems may require federal assistance worth billions of dollars to avoid bankruptcies [8].

INTER FUELS COMPETITION

Coal availability in the United States is not a problem. According to DOE, recoverable coal reserves in the U.S. total about 265 billion tons. About 61 billion tons of the U.S. recoverable coal reserves are in the Interior Region and about 80% of that is in the Illinois Basin, which includes parts of Illinois, Indiana and western Kentucky. Thus, nearly 49 billion tons of recoverable coal reserves, or 18.5% of the national total, are in the Illinois Basin [9]. However, the low-sulfur (<1.2 lbs SO_2 per million Btu) recoverable reserves in the U.S. are about 100 billion tons, very little of which is in the Interior Region. Little or no Illinois Basin coal can comply with the maximum allowable SO_2 limit through the year 2000 without additional cleaning or other forms of emission controls **(Figure 4)**. About 87% of the nation's low-sulfur coal reserves are in the western states, while 61% of high-sulfur (>3.36 lbs SO_2 per million Btu) recoverable coal reserves are in the Interior Region, mostly in the Illinois Basin.

Fuel cost is the main determinant of generating plants' operating cost but fuel choice is determined not only by its price but also by the cost of equipment needed to burn it cleanly and to safely dispose of waste. In the short run, the additional equipment costs disadvantage high-sulfur coal. In the long run, however, the deciding factor will be the cost of coal. To understand high-sulfur coal's current and near term disadvantage in comparison to other fuels, the cost of these fuels and the comparative costs of various pollution abatement strategies must be understood.

Pollution control and waste disposal costs of fossil fuels have been included in the price of coal-generated electricity, but the nuclear industry's costs of development and waste disposal have not been fully internalized, and insufficient money is being set aside to pay for the decommissioning of nuclear plants [10]. These un-internalized costs helped nuclear energy grow at exceedingly high annual rates in the past 25 years. Despite their low operating costs, nuclear plants are economically troubled by their stranded costs that must be recovered through higher rates, or borne by investors.

Gas-based generation increased at 2.4% per year during 1989 to 1995, after a sustained 16 year decline. Although gas based non-utility generation increased in 1996 and 1997, utilities used less gas than in 1995 with the result that total gas based generation remained unchanged. Delivered prices of natural gas to utilities increased 40 % in 1996-97. Gas fired power plants have important economic advantages because of their high thermal efficiency (60%) compared with coal-fired plants (40%). Gas-fired plants take only 1 to 3 years to build and cost at least 40% less than coal-fired plants [11]. Unlike in the 1980s, gas is no longer perceived as a commodity in short supply. DOE estimates proven U.S. gas reserves to be about 165 trillion cubic feet (Tcf), the equivalent of ten years of supply at the current rate of production. Seven times more than that can be found and produced at current prices and with currently available technology[12]. Planned capacity additions by electric utilities indicate that of the 32,000 MW to be added between 1993 and the year 2000, about 60% will be gas-based and only 20% coal-based [13].

According to the 1996 DOE annual energy outlook, the growth in coal-based electricity generation between 1995 and 2010 will come from an increase in capacity utilization from 62% to about 75%. No net addition to coal-based generating capacity is expected. Coal mined in the western states enjoys a price advantage over Midwestern coal primarily because mine productivity is high, mining costs are extremely low **(Table 1)**, and because average nationwide rail transportation rates declined 17% between 1986 and 1993 as a result of the transportation industry deregulation in the late 1970s [14]. As a result of increased use of Wyoming coal, the federal EPA reports a 2.3 million unit (1 Unit = 1 ton SO_2) over-compliance in January 1995. With this, almost half of the reductions targeted in the 1995-2000 period have already been achieved. A further increase in the use of low-sulfur coal through the year 2000 is likely.

THE KYOTO AGREEMENT

In December 1997, over 140 nations met in Kyoto, Japan, to discuss the possible effects of carbon dioxide emissions on global climate. The agreement reached at that meeting requires industrialized nations to reduce carbon emissions to an average of 7 percent below the 1990 carbon emission level by the year 2010. Most developing countries are exempt from these requirements because their current contributions to carbon emissions are low. The effectiveness of the Kyoto agreement is questionable for two reasons: 1) Economic growth rates in developing countries are two to three times those in developed countries. Thus, in twenty years most carbon emissions would be coming from those countries. 2) A reduction of carbon emissions to pre-1990 levels in industrialized countries would require a drastic reduction in energy consumption starting immediately. Such reductions would disrupt the entire world economy and threaten the livelihood of billions, including those in the developing countries that depend on exports to industrialized countries. The combined effects of the factors discussed above on the future demand for various fuels are summarized in the following chart: (An upward arrow indicating higher, a downward arrow lower demand)

	1990 CAAA	Deregulation	Kyoto agreement
Coal			
Low Cost	↑	↑	↓
High Cost	↓	↓	↓
Natural Gas	↑	↑	↑
Nuclear	↓	↓	↑ (?)

FUTURE OF HIGH-SULFUR COAL

The coal mining industry in the high-sulfur coal states has been hit hard by the dynamics of the coal market. High-sulfur coal production began to decline after the passage of the 1990 CAAA. Coal production in Illinois, Indiana, western Kentucky and Ohio declined by about 19 percent, from 176.5 million tons in 1990 to 143.3 million tons in 1997. Illinois coal production fell about 30%. Dozens of Illinois coal mines closed and over half the jobs were lost. Long-term sales contracts are declining rapidly. The future demand for high-sulfur coal will depend upon its price. The delivered prices of high-sulfur coals in most areas are higher than the prices of low-sulfur western coals. The conditions for high-sulfur coals in the first decade of the next century remain unchanged: slow growth in electricity demand, an even slower growth in coal-based electricity generation, and a higher price in comparison with low-sulfur western coal. Unfortunately, mine productivity in the high-sulfur coal states has not grown sufficiently to narrow the price gap. More power producers are opting for lower sulfur coals and natural gas. Under continuing prospects for lower coal production, the expected year 2010 production from Illinois, Indiana, western Kentucky and Ohio may be in the range of 100 to 105 million tons.

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(14)Philo, Gary R.; Keefe, Daniel, E; South, David W. and Bailey, Koby A.: Outlook for the Illinois Coal Industry, Dec. 1995, Illinois Coal Development Board, Illinois Department of Commerce and Community Affairs and Argonne National Laboratory, Table 2, page 11.

Table 1: Coal Prices at Mine and Productivity

	Mine price ($/t)	Productivity in 1995 (t/person/day)	Annual productivity change 1985-95 (%)
Illinois	23.05	3.87	5.6
Indiana	21.71	4.68	3.7
Kentucky			
East	26.00	3.47	4.6
West	20.75	3.97	3.4
Colorado	19.26	6.14	5.3
Montana	9.62	21.06	2.0
Wyoming	6.58	30.06	7.5

Source: DOE/EIA-0584(95) Coal Industry Annual 1995, Oct.1996, Table 48, Page 74 and Table 80, Page 154.

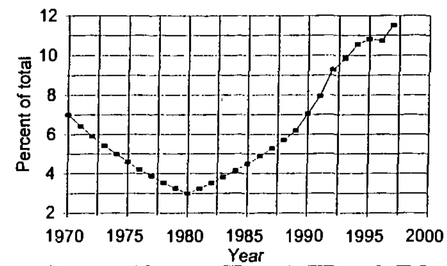

Figure 1: Share of non-utility generation of electricity in the U.S.

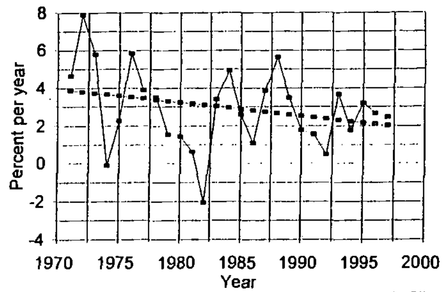

Figure 2: Growth rates in total U.S. electricity generation

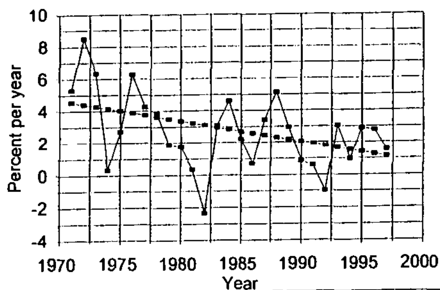

Figure 3: Growth rates in generation of electricity by utilities

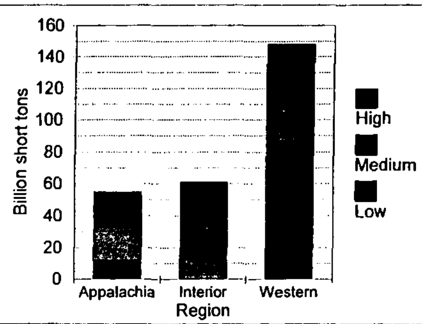

Figure 4: U.S.coal reserves by region and sulfur content